Year	System Operations		
	Feedstock Production	Transportation	Power Plant
-1	6½ fields in production	Transport of power plant equipment	Power plant construction
1	7 fields in production	Transport ½ of the biomass required for operation of the power plant at 80% capacity	Operation at 50% of 80% of capacity (40% capacity factor)
2-23	7 fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity Truck production and decommissioning of trucks in years 7, 15, and 22	Operation at 80% of capacity
24	6¾ fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
25	5¾ fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
26	4¾ fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
27	3¾ fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
28	2¾ fields in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
29	¾ of a field in production	Transport all of the biomass required for operation of the power plant at 80% capacity	Operation at 80% of capacity
30	Zero fields in production	Transport 75% of the biomass required for operation of the power plant at 80% capacity Decommission trucks and rail car	Operation at 75% of 80% of capacity (60% capacity factor) Decommission power plant

3.0 Technoeconomic Analysis

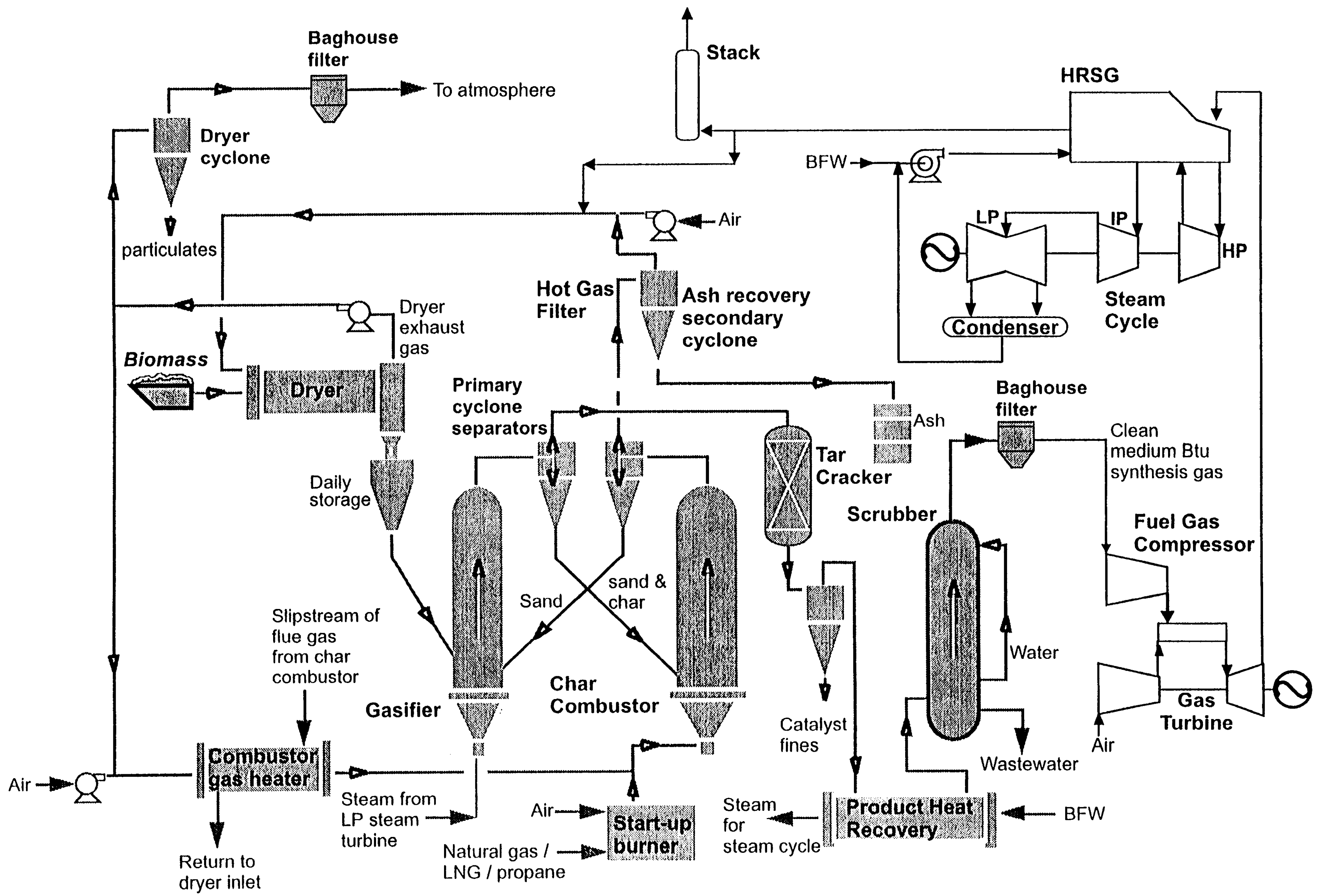
Generally, a process is analyzed based on what it will cost to build and operate, but environmental issues are clearly taking a more prominent role in project decision making. In order to better marry economic and environmental considerations, a technoeconomic analysis and life cycle assessment were conducted on the same process. An economic analysis previously performed for this biomass gasification combined cycle system was updated and a design change was incorporated to recycle a portion of the dryer exhaust gas to the char combustor in order to reduce the amount of VOCs emitted to the atmosphere. The original economic analysis for which the updated results are summarized below can be found in more detail in Craig and Mann (1996).

The low pressure indirectly-heated gasifier selected for this study was developed at Battelle Columbus Laboratories (BCL) specifically for biomass gasification. Future Energy Resources Corporation (FERCO) now owns the rights to the technology and is participating in its demonstration at the existing McNeil power plant in Burlington, Vermont. A schematic of this gasifier integrated with the combined cycle is shown in Figure 5. The distinctive feature of the BCL/FERCO unit is that unlike direct-fired gasifiers, which use both steam and air, only steam is injected with the biomass to promote gasification. Therefore, the fuel gas has a greater calorific value (12.7 MJ/m^3, 340 Btu/scf, LHV basis) than that produced by air-blown gasifiers (4.3 MJ/m^3, 115 Btu/scf, LHV basis). The heat necessary for the endothermic gasification reactions is supplied by sand circulating between a fluidized bed char combustor and the gasification vessel. In addition to acting as the heat source, the sand is the bed material for the gasifier, designed as an entrained fluidized bed reactor. Of the total amount of sand being circulated, 0.5% is purged to prevent ash build-up in the system. Because this stream is nearly 100% sand, it is assumed to be used in asphalt production.

The combined cycle investigated is based on the GE MS-6101FA utility gas turbine, an advanced turbine that moves GE's "F" technology (high firing temperature, high efficiency) down to a 70 MW-class machine. Gas turbine performance when using biomass-derived fuel gas was estimated based on the operating parameters (air flow, pressure ratio, firing temperature, outlet temperature) of the selected gas turbine (Anderson, 1993, and Gas Turbine World, 1993). A simulation was developed that matches its performance (output, heat rate) on natural gas fuel by "tuning" the efficiency of the various compression and expansion stages as well as adjusting heat losses, cooling air extraction etc. Utilizing these same "tuning" parameters, the resulting turbine model was incorporated, along with the biomass gasifier and cleanup section models, into a simulation of the overall gasification combined cycle plant. The simulation was configured such that the amount of biomass fed to the system was calculated based on the amount of gaseous fuel required by the gas turbine to achieve its design firing temperature. Changes in the gas turbine output and efficiency because of the increased mass flow of the lower energy content gas and the higher fuel gas temperature are thus roughly predicted.

To evaluate the performance of the BIGCC system, a detailed process model was developed in ASPEN Plus™. The material and energy balance results of the simulation were used to size and cost major pieces of equipment from which the resulting cost of electricity was calculated. The simulation calculates the overall biomass-to-electricity efficiency for the system based on total feed and the net electrical power produced. The major auxiliary equipment items (feed water pumps, boost compressor, blowers, etc.) are explicitly included in the simulation, and their power requirements are subtracted from the gross plant output. A 3% charge was taken against this preliminary net power (gross minus major equipment) to account for balance of plant electrical power including wood handling and drying.

Figure 5: Low Pressure Indirect BIGCC Schematic



3.1 Biomass Combined Cycle System Description

The biomass-based IGCC electric generating plant considered in the economic evaluation consists of the following process sections:

- Feedstock receiving and preparation island
  - Truck unloading system
  - Wood yard and storage
  - Sizing and conveying system
  - Dryers
  - Live storage area

- Gasification and gas cleaning
  - Wood feeding unit
  - Gasifier
  - Char combustion and air heating
  - Primary cyclone
  - Tar cracker
  - Gas quench
  - Particulate removal operation

- Power island
  - Gas turbine and generator
  - Heat Recovery Steam Generator (HRSG)
  - Steam turbine and generator
  - Condenser, cooling tower, feed water and blowdown treating unit

- General plant utilities and facilities

3.2 Model Description

The gasifier portion of the ASPEN Plus™ model was developed using experimental data from BCL 9 Mg/day process development unit (Bain, 1992). Because the gasifier operates at nearly atmospheric pressure (172 kPa, 25 psia), wood from the rotary dryers is fed to the gasifier using an injection screw feeder. Gasification occurs at 825°C (1,517°F), and combustion of the char occurs at 982°C (1,800°F). Fuel gas from the gasifier is cleaned using a tar cracker to reduce the molecular weight of the larger hydrocarbons, and a cyclone separator to remove particulates. A direct water quench is used to remove alkali species and cool the gas to 97°C (207°F) for compression. As an additional safeguard, a baghouse filter is also included to remove any fine particulates that were not removed in the cyclone separator and to ensure that any alkali species that were not removed in the quench are not introduced to the compression and turbine systems. Compression of the fuel gas prior to the gas turbine combustor is accomplished in a five-stage centrifugal compressor with interstage cooling. This compressor increases the pressure from 172 kPa to 2,068 kPa (25 psia to 300 psia). The maximum interstage temperature is 158°C (316°F), and the interstage coolers reduced the temperature of the syngas to 93°C (199°F). This unit operation was optimized at five stages according to the purchased equipment cost and horsepower requirements. After compression, the syngas is heated indirectly to 371°C (700°F) with process heat from the quench and char combustor flue gas.

Gas turbine exhaust is ducted to the heat recovery steam generator (HRSG), which incorporates a superheater, high and low pressure boilers, and economizers. Two percent boiler blowdown is assumed and feedwater heating and deaeration are performed in the HRSG system. All feedwater pumps are motor driven rather than steam turbine driven. In the steam cycle, superheated steam at 538°C and 10 MPa (1,000°F, 1,465 psia) is expanded in the high pressure turbine. The steam is then combined with steam from the low pressure (LP) boiler, reheated, and introduced into the intermediate pressure (IP) turbine. Exhaust from the IP turbine is passed though the LP turbine. Gasification steam is extracted from the LP exhaust and the remaining steam is condensed at 6,900 Pa (2 in. Hg). Expanded steam quality leaving the low pressure turbine is 90%. Assumed generator efficiency is 98.5%. The exhaust temperature from the HRSG, 140°C (284°F), is sufficiently high to avoid any possible corrosion in the stack and to mitigate steam plume visibility issues.

3.2.1 Wood Preparation and Drying

Design of the wood receiving, handling, and drying operations is based on a number of existing studies in this area (Breault and Morgan, 1992, Ebasco Environmental, 1993, and Wiltsee, 1993). The biomass used in the analysis is hybrid poplar; the elemental and property analysis for the biomass is shown in Table 3. Wood chips sized to fit through a two-inch screen are delivered by truck and train to the plant site; the delivered biomass price is assumed to be $46/bone dry Mg ($42/bone dry ton). The wood is unloaded and moved to the paved three-week storage yard, conveyed to the dryers (two in parallel), and then to the "live" or "day" storage bin from where it is fed to the gasifier. The average amount of biomass fed to the plant at 100% capacity, as dictated by the fuel requirements of the gas turbine, is 1,334 bone dry Mg per day (1,470 bone dry tons per day).

Table 3: Biomass Analysis - Ultimate Analysis for Hybrid Poplar

Component	Carbon	Oxygen	Hydrogen	Nitrogen	Sulfur	Chlorine	Ash
wt %, dry basis	50.88	41.90	6.04	0.17	0.09	0.00	0.92
Moisture, as received = 50%							

The wood dryers are of the co-current rotary drum type. Design conditions selected for the wood drying section result in a moisture content of 11% by weight. A mixture of ambient air, char combustor flue gas, and a large fraction of the HRSG exhaust gas is used for wood drying. Sufficient ambient air is mixed with the combustion products to reduce the gas temperature to 204°C (400°F) prior to introduction to the dryers. It is believed that this temperature is low enough to avoid the possibility of dryer fires. A slipstream of the dryer exhaust gas at 80°C (175°F), is recycled to the char combustor in order to reduce the amount of VOCs emitted to the atmosphere. This configuration is a change from the original design basis. The trade-off of recirculating a slipstream of the dryer exhaust gas is the cost of an additional blower and its electricity consumption in exchange for a reduction in dryer emissions. The remaining gas stream enters the dryer cyclone and then a baghouse to reduce particulate emissions before being emitted to the atmosphere. The temperature level at the baghouse is believed to be sufficiently low to mitigate fire danger. The dried wood exits the dryers at 68°C (155°F) and cools further during final transport to the feed system.

3.2.2 Gasification

The product gas composition, calculated by the simulation, is shown in Table 4. The design parameters and operating conditions of the gasifier are shown in Table 5.

Table 4: Gasifier Product Gas Composition, Dry Basis

Component	H_2	CO	CO_2	CH_4	C_2H_2	C_2H_4	C_2H_6	Tars	H_2S	NH_3
Volume %	33.68	36.35	11.34	13.33	0.30	3.89	0.39	0.34	0.07	0.32

LHV = 12.7 MJ/m^3 (340 Btu/scf)
HHV = 13.7 MJ/m^3 (368 Btu/scf)

Table 5: Gasifier Design Parameters and Operating Conditions

Gasifier temperature	826 °C (1519 °F)
Gasifier pressure	0.17 MPa (25 psia)
Dried wood feed to gasifier (11% moisture, 100% capacity)	1,498 Mg/day (1,651 t/day)
Dried wood moisture content	11%
Gasifier internal diameter	2.93 m (9.6 ft)
Steam / wood ratio (wt/wt, MAF)	0.45
Sand / wood ratio into gasifier (wt/wt)	19.5

3.2.3 Gas Turbine

The combined cycle investigated is based on the GE MS-6101FA, a utility-scale turbine with a pressure ratio of 14.9. The economic analysis performed showed that the increased gas turbine efficiency over smaller turbines offsets the costs of the higher system size and keeps the feed requirements within what might be available from a dedicated feedstock supply system (DFSS).

Hot (371°C, 700°F) clean fuel gas is introduced into the gas turbine combustor along with air from the high pressure turbine compressor. The fuel gas produced from the gasifier is well within the projected requirements for combustion of lower energy content gas in gas turbines. The use of a direct quench and humidification produces a fuel gas with higher moisture levels, which helps reduce formation of nitrogen oxides in the combustor and increases the mass flow through the turbine expander.

3.2.4 General Plant Requirements

The plant is assumed to be in close proximity to roads or railroad spurs adequate for delivery of the biomass feedstock. This is likely to be true when a DFSS is employed since the power plant would be sited near the center of the area in which biomass is produced.

In addition to the major process area equipment, a mechanical induced-draft cooling tower is assumed; all necessary pumps for condenser cooling and makeup water needs are included. Balance of plant equipment includes plant water supply and demineralization facilities, firewater system, waste water treating, service and instrument air system, and the electric auxiliary systems. General facilities included are roads, administrative, laboratory and maintenance buildings, potable water and sanitary facilities, lighting, heating and air conditioning, flare, fire water system, startup fuel system, and all necessary computer control systems.

3.3 Economic Analysis

The intent of the technoeconomic study (original design - Craig and Mann, 1996) was to evaluate the ultimate potential for application of IGCC technology to biomass-based power systems of large scale (> 30 MW_e). Therefore, the plant design was assumed to be for mature, "n^{th}-plant" systems. The aggressive sparing and redundancies typically utilized for "first-plant" designs and the attendant cost associated with such an approach were thus not applied.

3.3.1 Economic Analysis Methodology

The selling price of electricity in 1990 (the base year for the technoeconomic evaluation study) was $0.047/kWh, $0.073/kWh, and $0.078/kWh for industrial, commercial, and residential customers, respectively (U.S. Department of Energy, 1994). By calculating the economics of the processes being studied and comparing the results to the prices within the electricity generating market, the potential profitability can be assessed.

The levelized cost of electricity was calculated by setting the net present value of the investment to zero. The method and assumptions that were used to calculate the cost of electricity are based on those described in the EPRI Technical Assessment Guide (TAG) and reflect typical utility financing parameters. Independent power producers or cogenerators would clearly have different analysis criteria. A summary of the economic assumptions is presented in Table 6.

Table 6: Economic Assumptions

December, 1990 dollars 30 year project life 30 year book life 20 year tax life General plant facilities = 10% of process plant cost Project contingency = 15% of plant cost Two year construction period	Royalties = 0.5% of process plant cost Feedstock cost = $46/T ($42/t) Thirty days supply of fuel and consumable materials Accelerated Cost Recovery System (ACRS) depreciation Federal and state income tax rate = 41% Yearly inflation rate for calculation of current dollar cost = 4% Zero investment tax credit

Financial Structure		Current Dollar		Constant Dollar	
Type of Security	% of Total Capital Required	Cost/Interest rate, %	Return, %	Cost/Interest rate, %	Return, %
Debt	50	8.6	4.3	4.5	2.3
Preferred Stock	8	8.3	0.7	4.2	0.3
Common Stock	42	14.6	6.1	10.3	4.3
Discount Rate (before tax, cost of capital)			11.1		6.9

3.3.2 Capital Cost Estimates

Capital costs for the system were estimated using a combination of capacity-factored and equipment-based estimates. Capacity-factored estimates utilize the ratio of the capacity (flowrate, heat duty, etc.) of the new equipment to an existing piece of equipment multiplied by the cost of the existing equipment to estimate the cost of the new equipment. A scale-up factor particular to the equipment type was applied to the capacity ratio. The equipment-based estimates were determined from more detailed equipment design calculations based on the process conditions and results of the simulations. All costs were estimated in instantaneous 1990 dollars. Where necessary, costs were corrected to 1990 using the Marshall and Swift or Chemical Engineering equipment cost indices. In part, the base year of 1990 was chosen to facilitate a comparison of the costs with previous studies in this area. A charge of 20% of the installed cost of the major plant sections was applied to account for all balance of plant (BOP) equipment and facilities. The major equipment costs were multiplied by standard factors to arrive at the total direct cost of the installed equipment. Table 7 lists the factors used to determine total direct cost. These factors are for estimating the capital investment based on the total delivered equipment cost. In the design of the various pieces of process equipment, every effort was made to specify units that were modular and capable of being shop fabricated and shipped by rail.

Table 7: Factors Used for Calculation of Total Direct Plant Cost

Plant Cost	% of delivered equipment cost
purchased equipment-delivered	100%
Installation	15%
Piping	45%
Instrumentation	10%
Buildings and Structures	10%
Auxiliaries	25%
Outside Lines	10%
Total Direct Plant Cost (TDC)	215%

3.3.3 Overall System Performance

Process conditions and system performance for the system examined are summarized in Table 8. Net system output is 113 MW_e at a net system efficiency of 37.2%. This efficiency number is the fraction of the energy in the feedstock to the power plant that is delivered to the grid. Gas turbine output and efficiency based on fuel heating value are greater than those listed in the literature for natural gas fuel. These increases are primarily the result of high fuel gas temperatures and the increased mass flow through the turbine expander (due to lower energy content fuel gas).

Table 8: Process Data Summary and System Performance Results

Gasifier Requirements		**Fuel Gas Produced**	
Wood flowrate, Mg/day (t/day), 100% capacity	1,334 (1,470)	Fuel gas flowrate, kg/s (lb/hr)	13.3 (105,840)
Steam flowrate, kg/s (lb/hr)	6.9 (54,781)	Fuel gas heating value, LHV, MJ/m^3 (Btu/SCF)	12.7 (340.1)
Power Island		**Power Production Summary**	
Gas turbine	GE MS-6101FA	Gas turbine output, MW_e	78.6
Turbine PR	14.9	Steam turbine output, MW_e	52.4
Turbine firing temp, °C (°F)	1,288 (2,350)	Internal consumption, MW_e	18.1
Steam cycle conditions, MPa/°C/°C/ (psia/°F/°F)	10/538/538 (1,465/1,000/1,000)	Net system output, MW_e	113
		Net plant efficiency, %, HHV	37.2

3.3.4 Economic Analysis Results

The results of the economic analysis, including the levelized cost of electricity (COE) are shown in Table 9. The economic trade-off of recirculating a slipstream of the dryer exhaust gas is the cost of an additional blower and its electricity consumption in exchange for a reduction in dryer emissions. This design change results in a minimal increase in the selling price of electricity. The updated analysis shows the selling price of electricity to be 6.75 ¢/kWh in current dollars or 5.25 ¢/kWh in constant dollars for the system design described above.

Table 9: Summary of Technoeconomic Analysis Results

Output (MWe)	113
Efficiency (HHV)	37.2%
Capital cost (TCR, $/kW)	1,187
Operating cost including fuel ($1,000/yr)	25,891
COE (¢/kWh, Current $)	6.75
COE (¢/kWh, Constant 1990$)	5.25

4.0 Description of Process Blocks Studied in the LCA

The subsystems included in this life cycle assessment are biomass growth, transportation, and electricity production. Refer again to Figures 3 and 4 for the processes within these subsystems. Material and energy flows were quantified for each process block; details about the assumptions and data sources are given in the subsequent sections. To visualize how each upstream process is integrated with others in the system, the screen printouts from the TEAM software are attached as Appendix A. Emissions and energy use of some of the upstream processes were taken from the DEAM database (see section 2.5). The following schematic of the process blocks required for ammonium nitrate production serves as an example of how the total material and energy requirements for an intermediate feedstock were assessed. The data in some of the DEAM databases include the corresponding upstream processes in the block itself (e.g., natural gas production and reforming are included in ammonia production); these blocks are denoted with an asterisk.

Schematic Showing Process Blocks for Ammonium Nitrate Production